The Impact of Distribution Grid Tariff Design on the Value of Residential PV Generation in Belgium

~ Working paper ~

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Abstract

This paper examines the impact of various tariff policies for photovoltaics on the electricity distribution bill of residential customers. By means of synthetic load profiles and an average Belgian PV generation profile, the bill savings are simulated under different tariff designs, including conventional net metering, net metering with an additional capacity-based component, purely offtake-related tariffs, combined offtake and injection tariffs, and peak demand tariffs. This analysis is conducted on a case study of 7 distribution grid operators in Flanders, Belgium. In addition, bill savings are compared for different load profiles and degrees of PV penetration. It is found that NEM policies provide no incentive to change the load profile or scale the PV system in such a way that grid interaction and peak demand are minimized. The results suggest that pure offtake tariffs, combined offtake and injection tariffs and peak demand tariffs are better suited to incentivize lower grid interaction and peak demand, because marginal benefits of additional PV capacity decrease for high levels of PV penetration. Lastly, the results indicate that the ability of PV systems to reduce peak demand and grid interaction of an average Flemish household is limited.

Keywords: distribution grid tariffs, cost allocation, rooftop photovoltaic generation, net metering, capacity-based tariff

1. Introduction

Historically, the allocation of electricity distribution costs to grid users has always been subject to a degree of economic inefficiency, in the sense that users do not carry a share of the costs that perfectly reflects their contribution in causing these costs. In economic theory, the optimal setting of prices for use of infrastructures which are too costly to duplicate is a well-studied and much debated issue, first addressed by economists in the context of bridge tolls (Dupuit, 1849). Many theorists in the early twentieth century advocated marginal-cost pricing as the most allocative efficient pricing method to maximize social welfare, including Pigou (1920) and Knight (1924) who apply it to road taxation in the presence of congestion, and Hotelling (1938) in the context of public utilities.

There are various reasons why tariff methodologies for distribution grid operators (DSOs) deviate from this theory in practice. First, the DSO is a textbook example of a natural monopoly (Baldwin, et al., 2011) and marginal-cost pricing is shown to be financially unfeasible for natural monopolies who are characterized by economies of scale and a significant share of fixed costs (Kahn, 1988). Second, it may not be consistent with other objectives of policy makers and regulators, such as non-discrimination, regulatory stability and simplicity. As a result, a substantial part of distribution grid costs is traditionally allocated on the basis of energy offtake, or as a fixed yearly charge, with little or no attention to other cost determinants such as time of use or contribution to peak load.

Nowadays, the historical problems related to economic efficiency of cost allocation in distribution grids are amplified due to the increasing integration of distributed and renewable generation into the low-voltage grids. Between 2002 and 2012, total solar generation in the EU-28 rose from 0.3 TWh to 71.0 TWh, and its contribution to renewable generation rose from 0.1% to 10.5% (Eurostat, 2014). By the end of 2013, installed PV capacity amounted to 78.8 GW_p, with an output of 80,2 TWh (≈ 2.4% of annual EU generation) (Eurobserv, 2014). In many regions, solar photovoltaic (PV) panels have become widespread among residential customer-generators, here referred to as 'prosumers'. Distributed generation (DG) is challenging DSOs in several ways. On the one hand, there are technical challenges, such as congestion management and voltage control when dealing with reverse power flows and local injection peaks. On the other hand, there is a regulatory challenge in finding a sound balance between promoting renewable DG and demanding a fair contribution of DG for usage of the grid.

This paper aims to quantify the impact of residential PV on the annual electricity distribution bill.[1] The potential bill savings are simulated and compared under different PV tariff policies, PV penetration levels, load profiles. From the perspective of the DSO, these bill savings are a measure for the premium given to PV generation, which is, ceteris paribus, paid by other grid users. The bill savings are simulated using the current tariff schemes of 7 Flemish DSOs. In particular, 5 distinct tariff policies for PV are analyzed: conventional net metering, net metering with an additional capacity-based component, purely offtake-related tariffs, offtake and injection tariffs, and peak load tariffs. The emphasis of this work lies on the comparison of the behavior of the different tariff policies under varying degrees of PV penetration, and under varying load profiles.

While several authors have already explored the bill saving potential of PV systems, there has been no study on the isolated effect of PV tariff policies on the contribution of residential users to the distribution grid costs. This paper fills that gap and quantifies the impact of PV systems on the premium given by DSOs to prosumers as opposed to pure consumers. The results of this study are of interest to regulators and policymakers who wish to make an impact assessment of different solar PV policies on the contribution of PV users to the distribution grid costs, and of the way in which these policies behave under changing PV penetration levels. Likewise, the results may assist grid users in assessing the value of PV for investment decisions.

Section 2 provides theoretical background on cost allocation in distribution grids and definitions of the main concepts in this paper. In addition, it covers closely related literature, and highlights the characteristics of distribution grid tariffs in Flanders. Section 3 describes the input data and the methodology. Section 4 summarizes the results for each PV tariff policy, and compares bill savings for different values of PV penetration and load profiles. Finally, section 6 concludes.

2. Cost allocation in theory and in practice

2.1 Economic regulation versus cost allocation

Due to the natural monopoly characteristics of electricity networks, the activities of DSOs are typically supervised by a regulator (Joskow, 2007). From an economic perspective, two closely related types of regulation can be distinguished: economic regulation and cost allocation. The objective of economic regulation is generally to create an economic framework for DSOs that

[1] In practice, the bill of a residential consumer also has components related to energy, transmission and taxes, but these components are not accounted for. This paper focuses on the distribution component.

mitigates the negative monopoly effects by mimicking the forces of a competitive environment. In practice, this means that the regulator supervises the aggregate costs and revenues of the DSO in order to ensure operational efficiency and a reasonable rate of return. Important examples of approaches to economic regulation include incentive regulation and cost-of-service regulation (Joskow, 2014). Cost allocation, on the other hand, is concerned with the question how the allowed costs should be allocated among the grid users. Similarly to economic regulation, this usually happens with oversight from regulators who design the tariff structure and other mechanisms (e.g. net metering) which can impact the final allocation. The work of Laffont & Tirole (1993) constitutes a fundamental reference on the historical development of the theory of monopoly pricing.

2.2 Principles of tariff design

When designing the distribution grid tariffs, regulators seek a balance between several, often conflicting, objectives. Examples of typical principles of tariff design include (Pérez-Arriaga (2013), Bonbright (1961)):[2]

- *Economic efficiency*: an efficient allocation is one where goods and services are consumed by whoever benefits most from hem. Because prices have an important signaling function, they can be designed to incentivize grid usage that is most efficient for the system as a whole. Economic theory suggests that this requires prices that reflect marginal costs. This closely relates to the concept of cost-causality, which states that customers should be charged in accordance with the costs they cause to the system. In this context, economic efficiency implies that tariff drivers should represent cost drivers for the DSO.
- *Economic sustainability*: often referred to as 'revenue sufficiency'. Tariffs should be designed in such a way that DSOs are capable of recovering their allowed costs in the short- and long-term, and of guaranteeing a reasonable rate of return. This principle may conflict with the principle of economic efficiency, since optimal economic signals may not be financially feasible in the long-term.
- *Non-discrimination*: in the context of cost allocation, it is often referred to as 'equity'. This principle states that the same usage of the grid should result in the same bill for different grid users.
- *Simplicity*: this principle requires that tariff methodologies should be easy to understand and to implement. It conflicts with the objective of economic efficiency, because any simplification of an economically optimal tariff design ultimately distorts the efficiency of the signals given to grid users.

At the same time, tariff design has to be technically feasible. Tariff drivers have to be objectively measurable at the customer side, requiring adequate metering equipment. Most traditional electromechanical meters measure the flow of electrical energy (in kWh). They can be unidirectional or bi-directional, meaning that the meter can rotate in two directions, depending on the direction of the current. Newer, digital meters can register several flows separately and can even account for time of use (Hughes & Bell, 2004).

These design principles and implementation constraints commonly results in the following types of charges (Mills, et al., 2008):

[2] Other principles include: consistency, transparency, additivity, and stability.

- *Energy-related charges*, based on electricity offtake and/or injection during a pre-specified period of time.
- *Capacity-related charges*, based on peak offtake and/or injection, or peak capacity of the connection. In the context of DG, these charges can also be based on the capacity of the DG system.
- *Fixed charges*, based on factors not directly related to grid usage. Examples include location in the grid (city versus rural) or metering activities.

One of the greatest challenges in cost allocation today lies in determining the weight given to each of these types of charges in recovering the costs of the DSO, while accounting for the design criteria mentioned above. Additionally, the question remains how to optimally implement each charge.

2.3 PV remuneration mechanisms

Alongside tariff design, other mechanisms exist which impact the allocation of costs among grid users. This includes the way in which users are compensated for PV generation. Hughes & Bell (2004) provide a taxonomy of various methods for compensation of customer-generators for electricity injected into the grid. In Europe, two types of PV compensation are most common: feed-in tariffs (FIT) and net metering (NEM). Both are designed to accelerate investment in renewable generation, but this paper only considers the impact of PV under NEM.

Most practical applications of FIT policies are characterized by long-term contracts in which the renewable generator is guaranteed a certain price, dependent on the underlying cost of the generation technology (Couture & Gagnon, 2010). This feed-in price can be, but does not have to be, equal to the prevailing retail rate. NEM, on the other hand, can be defined as a service to an electric consumer, allowing electric energy provided by the utility to the consumer to be offset by electric energy generated by that consumer from an eligible on-site generating facility and delivered to the local distribution facilities (FERC, 2005).[3] This implies that all local generation is credited at the retail rate, which includes the energy price, the grid tariffs for transmission and distribution, and the regional and national levies. Any excess generation above local consumption (i.e. when the volume of injections exceeds the offtake during the billing period) is typically not reimbursed, although some countries allow carrying over excess generation as a credit from one billing period to the next, which is commonly referred to as ‘banking’ (Hughes & Bell, 2004).

An important aspect of NEM is that the temporal correlation between local consumption and generation is disregarded. Under a fully volumetric distribution grid tariff, users with the same aggregate consumption and generation receive the same bill, regardless of any differences in load shape and simultaneity. Charges based on peak demand are more sensitive to this temporal correlation, making the benefits of PV less predictable. Some studies already illustrate how the value of NEM for PV owners is strongly affected by rate design (Mills, et al., 2008), explaining why solar advocates may have a preference for volumetric charges.

[3] In practice, a single, bi-directional meter is commonly used. In the case of NEM, a single, bi-directional meter is commonly used to register the electricity consumption of the grid user. When local generation exceeds local consumption, electricity is injected into the grid, and the meter runs backwards. The annual bill is then based on the difference between the meter readings at the end and the beginning of the year.

2.4 Related literature

Multiple authors have studied the impact of PV systems on peak load and peak load charges. Hoff, et al. (1992) show that small PV systems, relative to the maximum building load, can lead to significant reductions in energy charges and peak load charges. This analysis is conducted using consumption data of an office building, and simulated PV generation profiles. However, it is also found that the ability of PV systems to reduce peak load declines substantially as the size of the PV system increases, due to a shift of peak demand to moments when PV generation is low. Perez, et al. (1997) analyze the ability of PV systems to reduce peak load. The authors find that this peak reduction ability is highest in air-conditioned offices. Bhattacharjee and Duffy (2006) analyze the payback period of PV systems, and find that the length of this period decreases when peak load charges savings are accounted for. Borenstein (2008) attempts to make a complete market valuation of solar PV. It is found that the market benefits of PV are much smaller than the costs. In addition, the results suggest that installation of solar systems in California does not reduce the cost of transmission and distribution infrastructure.

Other studies examine the relation between rate design and the value of PV systems. Herig and Starrs (2002) compare the impact of volumetric versus fixed rates on the value of PV systems. Hoff and Margolis (2004) and Pop (2005) compare the impact of time-of-use rates versus flat rates on the value of a residential PV system. Johnston, et al. (2005) analyze the impact of standby rates on DG. Duke, et al. (2005) study net metering. Firestone, et al. (2006) study the impact of rate structure on DG in New York and California. Cooper & Rose (2006) review the status and importance of net metering at the state level. Mills, et al. (2008) explore the ability of PV systems to create bill savings for commercial customers under a large number of retail rate structures in California, comparing multiple actual building loads and PV generation combinations. The authors also address the impact of rate switching, and the value of NEM.

2.5 Cost allocation in Flanders

In Flanders, the design of distribution grid tariffs is determined by the regional regulator VREG. The tariff covers 5 cost components:

1. *Costs related to usage of the grid*: this component covers costs which can be attributed to the subscribed capacity, the system services and the metering activity.

2. *Costs related to public service obligations*: this component covers expenses which are imposed by the government, such as street lighting, the purchasing of green certificates, and the costs of acting as a social electricity supplier toward poor users who are not eligible for another supplier.

3. *Costs related to supporting services*: among other things, this component covers costs due to energy losses in the grid.

4. *Surcharges*: covering the remaining local, regional and federal taxes.

5. *Supplementary capacity charge for prosumers with net metering*: this is a newly introduced tariff component for prosumers under the net metering policy, to compensate for the fact that this group generally does not fully contribute to the costs associated with their real

electricity offtake, because the meter only visualizes the *net-offtake* instead of the full annual offtake.

Each of these cost components is recovered through a number of tariff drivers, including energy offtake and injection (€/kWh), peak demand (€/kW), PV capacity (€/kW), and fixed charges (€/year). Tariffs and tariff structure are dependent on the type of user and the type of metering installed. In general, the distribution grid tariffs are heavily volumetric. Furthermore, tariffs are strongly focused around energy offtake. Injection tariffs are only compulsory for systems with a peak capacity > 10kVA. PV systems below 10 kVA are eligible for a NEM policy.

3. Data and methodology

3.1 Input data

This paper uses three types of input data: synthetic load profiles, a PV generation profile, and the tariff sheets of Flemish DSOs. Each of these inputs is discussed below.

A. Synthetic Load Profiles

Synthetic load profiles (SLPs) are artificial curves, representing the estimated average consumption behavior of certain categories of grid users who do not have a meter which registers and transmits real-time consumption data. An SLP typically represents consumption on a quarter-hourly basis, relative to the annual total consumption, and accounting for various determinants, such as differences between consumption during the week versus the weekend, and climatological and seasonal effects. In this paper, two quarter-hourly SLPs for residential households are used, which have the following characteristics:

$$SLP1: \quad \frac{Night - time\ consumption}{Daytime\ consumption} < 1.3$$

$$SLP2: \quad \frac{Night - time\ consumption}{Daytime\ consumption} \geq 1.3$$

These SLPs are applicable to the year 2015, and were constructed by Synergrid, the federation of Belgian grid operators for electricity and gas (VREG, 2015). SLP1 is the consumption profile of an average residential consumer in Flanders. SLP2 is the average consumption profile of residential consumers who consume relatively more at night. These are typically users who have a contract for separate day- and night-rates with their supplier. In both cases, an annual electricity consumption of 3500 kWh is assumed.[4] Figure 1 illustrates the difference in load shape between SLP1 and SLP2.

[4] 3.500 kWh is the annual consumption of an average Flemish household consisting of two parents with one child, assuming no electric heating (VREG, 2015)

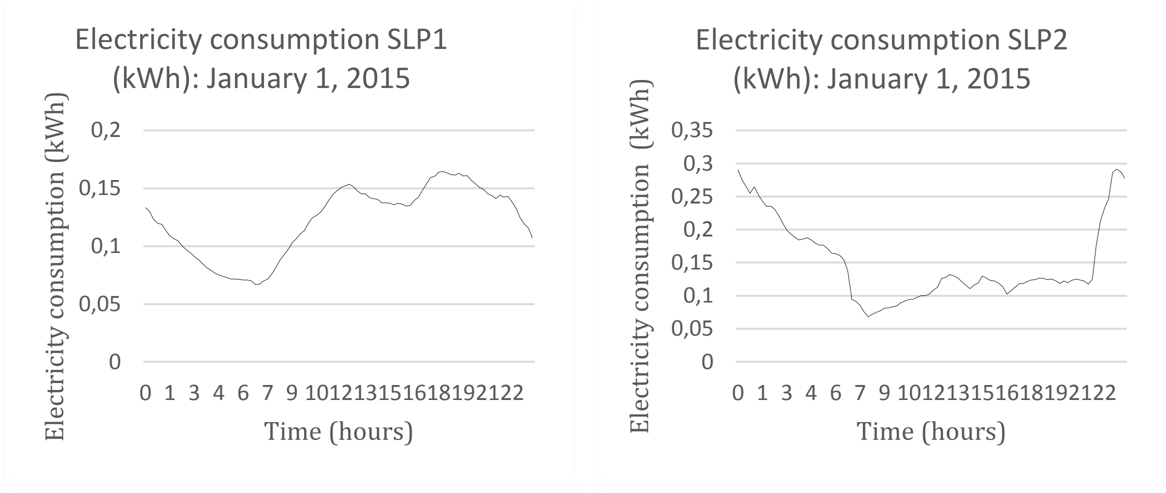

FIGURE 1: Comparison of load profile shape between SLP1 and SLP2.

B. PV generation profiles

The Belgian transmission system operator (TSO) Elia publishes country-wide generation data for various technologies connected to the Belgian electricity grids, including solar generation (Elia, 2015). For each quarter-hour interval of the year 2013, both the monitored capacity (MW) of each technology, and the average momentary measurement (MW) are known. From this, we derive the PV output profile. In what follows, this profile is referred to as 'PV2013'.[5]

$$Output_t(\%) = \frac{Measurement_t(MW)}{Monitored\ capacity_t(MW)}\ \forall\ t\ \in T\ (= 1,2, \dots, 35040)$$

In order to translate this into a more practical physical quantity, such as power (kW) or energy (kWh), one needs to know the size of the PV system in terms of its peak capacity (kW). By changing the peak capacity of the installation, it is possible to up- or downscale the generation profile. However, in this paper *PV penetration* is used as an input parameter to represent and scale the size of the PV system, instead of peak capacity. PV penetration can be defined as follows:[6]

$$PV\ penetration\ (\%) = \frac{Annual\ generation\ (kWh)}{Annual\ consumption\ (kWh)}$$

By combining PV2013 with SLP1 and SLP2 respectively, it is possible to create two separate consumption-generation scenarios, and to compare the way in which both interact with the electricity distribution grid. Figure 2 summarizes some important characteristics of these combinations with respect to electrical energy flows. Figure 3 visualizes the ability of PV systems to reduce peak demand. The following observations can be made:

- *Annual offtake*: electricity offtake during each 15-minute interval can be defined as follows:[7]

[5] In other words, it is assumed that every solar PV system in the country has the same relative output, averaging out differences in local weather conditions, technological differences, and differences in orientation and angle of the system.

[6] Note that in this paper, only PV penetration between 0% and 100% are considered.

[7] By this definition, any injection of electricity into the distribution grid is simply a negative offtake.

$$Offtake_t(kWh) = Consumption_t(kWh) - Generation_t(kWh)$$

The upper left graph in Figure 2 visualizes the annual offtake for PV penetration levels between 0% and 100%, which is defined as:

$$Annual\ offtake(kWh) = \sum_t Offtake_t(kWh)[Offtake_t > 0]$$

It can be observed that for small levels of PV penetration, both SLPs have the same offtake behavior. In both cases, the PV system decreases grid offtake at a similar rate at times during the day when the sun is up. However, from ±12% PV penetration onwards, offtake declines less steeply for SLP2. This is because SLP2 is generally consuming less at times when PV generation is high, leaving less room for offtake reductions.

- *Annual injection:* this is calculated using the following formula:

$$Annual\ injection\ (kWh) = \sum_t Offtake_t(kWh)[Offtake_t < 0]$$

The upper right graph in Figure 2 shows that the threshold for injections is lower for SLP2 (±7% PV penetration) than for SLP1 (±12% PV penetration). This is because SLP2 consumption is generally lower during times when PV generation is high.

- *Annual grid interaction*: this is calculated as the sum of annual offtake and injection. The lower left graph in Figure 2 shows the result for varying levels of PV penetration. For both profiles, PV systems are shown to allow reduction of the total volumetric grid interaction. However, the ability to reduce grid interaction is limited, due to the fact that PV systems only generate during the day-time. Hence, there exists a PV penetration level where grid interaction is minimal. Due to the same reasons explained above, this level is lower for SLP2 (±18% PV penetration) than for SLP1 (±28% PV penetration). In the case of SLP1, this translates into a maximum 20% reduction in grid interaction.

- *Meter reading (NEM)*: due to the fact that NEM policies allow for offtake to be offset by injection, the end-of-the-year meter reading is computed as follows:

$$Meter\ reading\ (kWh) = \sum_t Offtake_t\ (kWh)$$

This is equivalent to the difference between annual offtake and injection. The lower left graph in Figure 2 visualizes the result. It is found that for both consumption profiles, the meter reading declines linearly for increasing levels of PV penetration. This is because in both cases the annual demand and generation is the same, and because annual generation increases linearly with PV penetration. This illustrates the point made in subsection 2.3 that NEM policies do not account for differences in simultaneity between consumption and generation.

- *Peak demand reductions*: the relative reductions in peak demand during each month m of the year 2013 are computed as follows:

$$Peak\ demand\ reduction_m = \frac{Max(Offtake_{t \in m}|PV\ penetration = 0) - Max(Offtake_{t \in m})}{Max(Offtake_{t \in m}|PV\ penetration = 0)}$$

Figure 4 summarizes the results for SLP1. It is found that PV generation can only reduce monthly peak demand for SLP1, and this is limited to the months April, May, June, July and August. Highest possible demand reductions at 100% PV penetration are observed in July (±14%). It is also found that, in any month, the highest peak demand reductions are reached at ±10% PV penetration. In other words, additional PV system capacity above this threshold has little or no added value in reducing peak demand. It is also found that peak demand reductions are not possible for SLP2, since peak demand generally occurs during night-time.

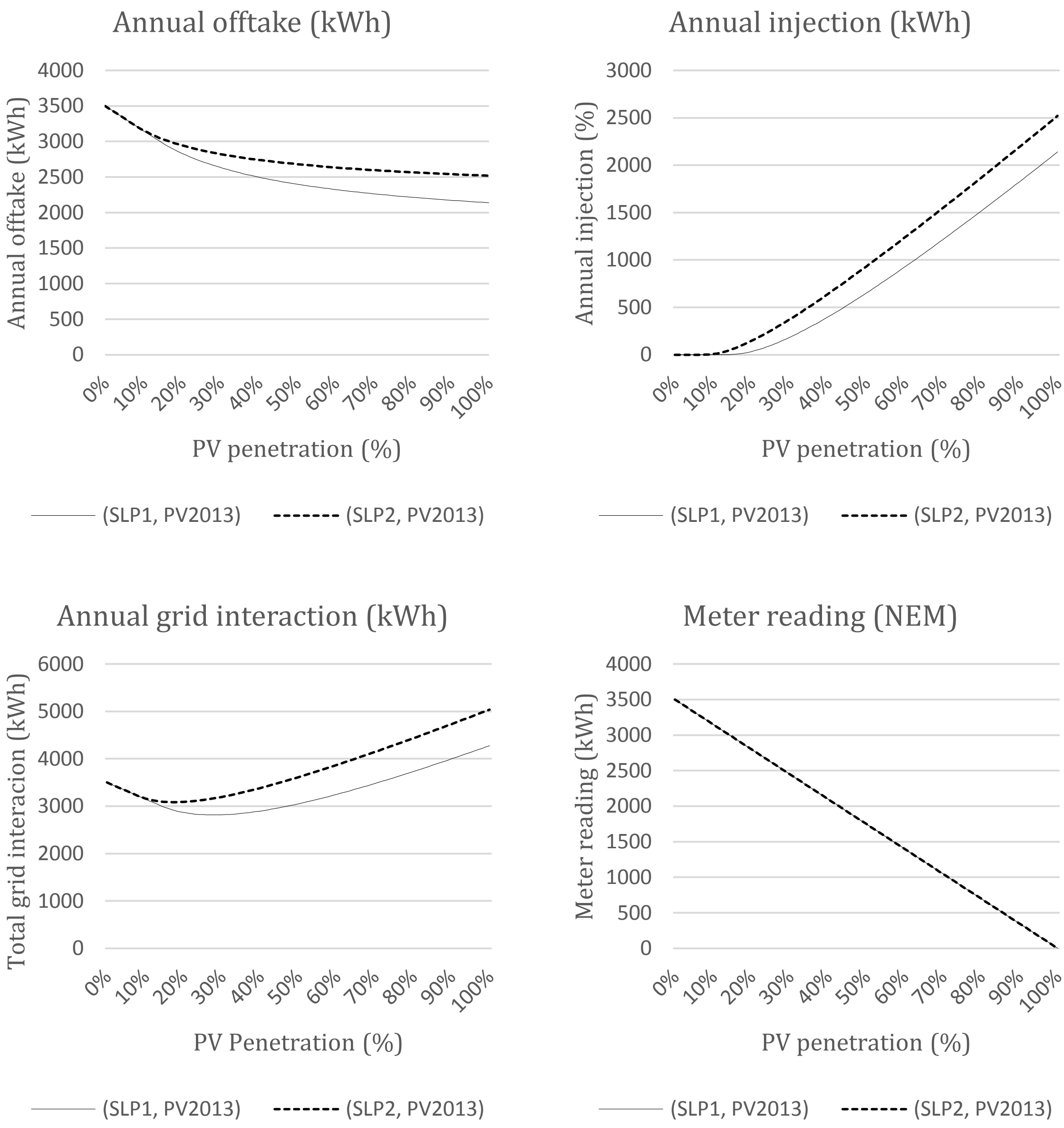

FIGURE 2: Characteristics of the generation and consumption profiles.

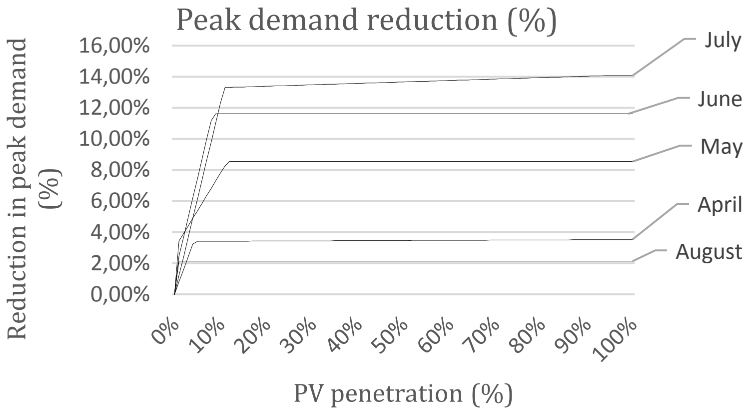

FIGURE 3: Ability of PV systems to reduce peak demand.

C. Tariff Sheets

The Flemish regulator VREG is responsible for developing a methodology for calculating the distribution grid tariffs of the DSOs active in Flanders.[8] The DSOs subsequently apply this methodology to their own cost structure, and because of both absolute and relative differences in this cost structure, the final tariffs may be different. Nevertheless, the overall structure of the distribution grid bill is the same for every customer within the same customer category. A complete overview of the distribution grid tariffs is available on the website of the regulator (VREG, 2015).

The tariff sheets of the Flemish DSOs are composed of five cost components, as discussed in section 2. Each component is then further divided into several sub-components which are all reimbursed through an associated tariff driver. Table 1 provides a more accessible summary of the prices in € for each tariff driver, for each DSO $i \in I$ ($I = \{1,2,\dots,7\}$), and for different energy flows and types of metering regime. The following tariff drivers are used in Flanders:

- Energy offtake or injection (€/kWh): $\alpha_1(i), \alpha_2(i), \alpha_3(i)$
- Peak demand (€/kW): $\beta_1(i), \beta_2(i), \beta_3(i)$
- Installed PV capacity (€/kW): $\gamma_1(i), \gamma_2(i), \gamma_2(i)$
- Fixed charge (€/year): $\delta_1(i), \delta_2(i), \delta_3(i)$

Note that in Flanders, most costs are recovered on the basis of electric energy offtake, or net-offtake in the case of net metering. Injection tariffs are generally only applicable to larger DG systems (>10 kVA), and require a more advanced meter than the traditional single meter. NEM is allowed for all PV systems with a peak capacity ≤10 kVA. Peak metering is normally used by professional customers, with a peak demand greater than 56 kVA, and mandatory for any user with a peak demand of at least 100 kVA. In this paper, the focus is on residential households. However, for the sake of comparison, the household distribution bills are computed using tariffs which are normally not applicable to this type of grid user.

[8] Up until July 2014, the development of the distribution grid tariff methodology was still a federal affair, attributed to the national regulator CREG.

			GASELWEST	IMEA	IMEWO	INTERGEM	IVEKA	IVERLEK	SIBELGAS
OFFTAKE	Traditional metering (Incl. NEM)	Energy (α_1)	0,1330	0,0888	0,1050	0,1002	0,1004	0,1080	0,1196
		Peak demand (β_1)	0	0	0	0	0	0	0
		PV capacity (γ_1)	83,99	62,9	70,31	68,27	66,90	71,15	79,16
		Fixed (δ_1)	9,42	9,42	9,42	9,42	9,42	9,42	9,42
	Peak metering	Energy (α_2)	0,0572	0,0489	0,0475	0,0487	0,0498	0,0518	0,0602
		Peak demand (β_2)	118,94	65,61	90,65	80,39	80,71	89,36	94,18
		PV capacity (γ_2)	0	0	0	0	0	0	0
		Fixed (δ_2)	157	157	157	157	157	157	157
INJECTION		Energy (α_3)	0,005303	0,005708	0,005875	0,006125	0,006388	0,006512	0,009450
		Peak demand (β_3)	0	0	0	0	0	0	0
		PV capacity (γ_3)	0	0	0	0	0	0	0
		Fixed (δ_3)	157,00	157,00	157,00	157,00	157,00	157,00	157,00

TABLE 1: Summary of the distribution grid tariffs (€) in Flanders for offtake and injection, and for traditional metering and peak metering.

3.2 Methodology

Distribution bills are calculated differently depending on the PV policy in place. We consider the following policies:

- Conventional net metering (P1): Under this policy, the user is only receives volumetric charges related to offtake, which is measured through a traditional, single meter with net metering capability. There is an energy charge and a fixed charge, but no injection tariff. The following formula is used to compute the bill:

$$Annual\ Bill(B1) = \alpha_1(i) * Meter\ reading + \delta_1(i) \quad \forall i \in I$$

- Advanced net metering (P2): This is the actual net metering policy in Flanders today. The only difference with P1 is an additional tariff based on the capacity of the PV system. The following formula is used:

$$Annual\ Bill\ (B2) = \alpha_1(i) * Meter\ reading + \gamma_1(i) * Peak\ capacity + \delta_1(i) \quad \forall i \in I$$

- Pure offtake policy (P3): Under this policy, the user only pays volumetric charges related to offtake, which is measured through an advanced meter registering offtake and injection separately. This meter comes at a higher price, and hence leads to higher fixed charges. Furthermore, there is no injection tariff. The bill consists of an energy charge and a fixed charge, using the following formula:

$$Annual\ Bill\ (B3) = \alpha_1(i) * Annual\ offtake + \delta_3(i) \quad \forall i \in I$$

- Injection tariff policy (P4): Here, an advanced meter is installed registering offtake and injection separately. The annual offtake is charged at the offtake energy charge, while the annual injection is charged with an injection tariff. Furthermore, there is a fixed charge. The following formula calculates the bill:

$$Annual\ Bill\ (B4) = \alpha_1(i) * Annual\ offtake + \alpha_3(i) * Annual\ injection + \delta_3(i) \quad \forall i \in I$$

- Peak metering (P5): The volumetric energy charges only account for offtake. There are no injection tariffs. Additionally, there is a peak demand tariff, and a higher fixed charge due to the advanced metering. The annual tariff for peak demand is calculated on a monthly basis, and based on the peak offtake during all the previous months, up to 1 year. This translates to the following formula:

$$Annual\ Bill\ (B5) = \alpha_2(i) * Annual\ offtake + \beta_2(i) * \left[\sum_{P\in\varphi} Max(4 * Offtake_t[t \in P])\right] + \delta_2(i) \quad \forall i \in I$$

$$With\ \varphi = the\ set\ of\ all\ subperiods\ P\ in\ T = \{(Month\ 1), (Month\ 1 + Month\ 2), (Month\ 1 + Month\ 2 + Month\ 3), \dots, (all\ 12\ months)\}$$

The aim of this paper is to simulate the distribution bill of household consumers under each PV policy, and for each load profile and level of PV penetration. Subsequently, the bill savings (PV premia) granted to PV systems are calculated. In particular, we consider the following combinations: five PV policies, seven different Flemish DSOs and their associated tariffs, two load profiles, and PV penetration levels ranging from 0% to 100%. Similarly to Mills (2008), bill savings (PV premia) are defined as follows:

$$Bill\ saving\ \left(\frac{€}{kWh}\right) = \frac{Annual\ bill\ [PV\ penetration = 0] - Annual\ bill\ [PV\ penetration \neq 0]}{Annual\ generation}$$

Bill savings are quantified on a per kWh basis because it is evident that larger systems generate more electricity, and therefore lead to greater absolute bill savings under a NEM policy, or greater injection tariffs under an injection policy. This notation allows to abstract from the specific physical size of the PV system and to focus on relative differences in bill savings.

4. Description of the results

4.1 Conventional net metering

Figure 5 visualizes the distribution bill savings resulting from PV generation under a conventional NEM policy. It can be observed that the shape of the load profile has no effect on the obtained bill savings. This is because the bill is dependent on the meter reading, which does not account for differences in temporal correlation between generation and load, as is illustrated in subsection 3.1 B. Furthermore, since generation increases linearly as a function of PV penetration, and since the meter reading decreases linearly as a function of PV penetration, the marginal benefit per kWh of additional PV capacity is constant. Note that significant differences in bill savings are observed among the different DSOs. This is because the offtake tariffs α_1 vary, as depicted in Table 1.

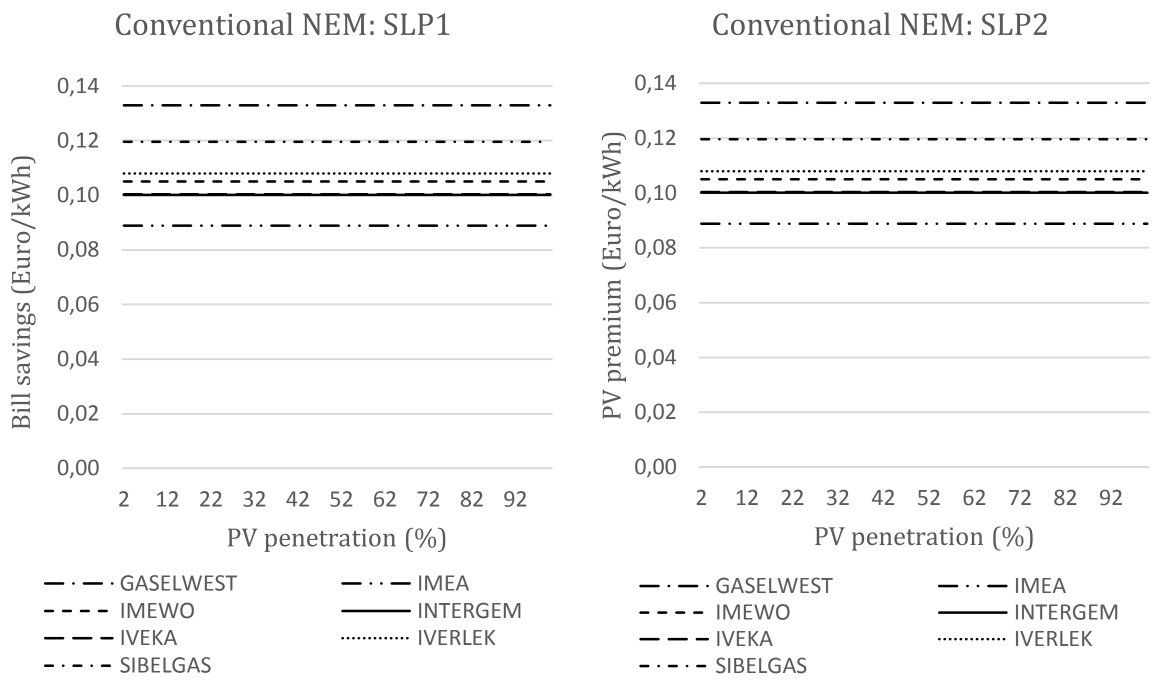

FIGURE 5: Bill savings under a conventional NEM policy.

4.2 Advanced net metering

Bill savings resulting from an advanced NEM policy are depicted in Figure 6. Similarly to conventional NEM, shape of the load profile has no impact, and marginal benefits of PV capacity are constant. However, the additional tariff component based on the capacity of the PV system significantly decreases the benefit per kWh generated, at each level of PV penetration. Lastly, it can be observed that the differences between DSOs are more outspoken than in the case of conventional NEM, due to differences in the capacity-based tariff component γ_1(Table 1).

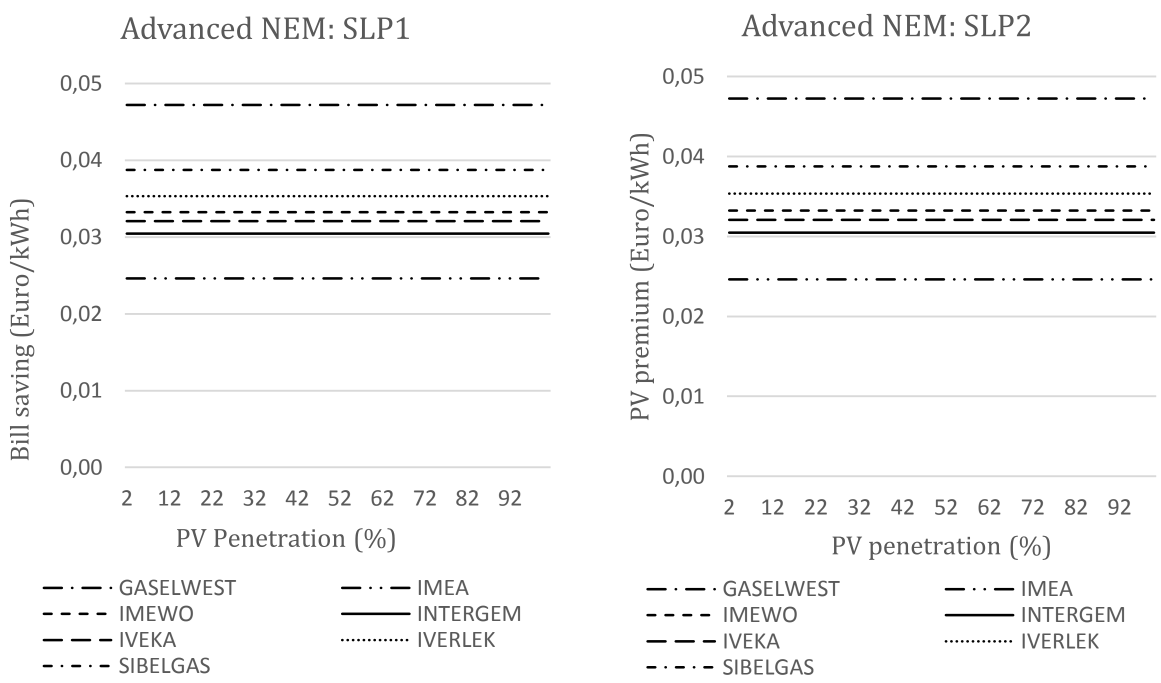

FIGURE 6: Bill savings under an advanced net metering policy.

4.3 Pure offtake policy

The potential bill savings under a purely offtake-related distribution grid tariff are depicted in Figure 7. It can be observed that bill savings are generally higher for SLP1 than for SLP2. This can be explained by the fact that annual offtake is typically lower for SLP1 at all levels of PV penetration, due to the increased temporal correlation between consumption and generation. In addition, it appears bill savings per kWh are strongly dependent on PV penetration, displaying decreasing marginal returns of additional PV capacity beyond a certain threshold. This result follows from the observation that annual offtake does not linearly decrease for increasing levels of PV penetration. Beyond ±10% PV penetration, some of the PV generation is injected into the grid, not further reducing electricity offtake. This does not happen for small levels of PV penetration, hence the constant marginal gains from additional PV generation. Note that differences in bill savings between DSOs decrease as PV penetration increases. This can be explained by the fact that at 100% PV penetration, electricity offtake is minimized. Therefore, differences in offtake tariffs (α_1) are less outspoken.

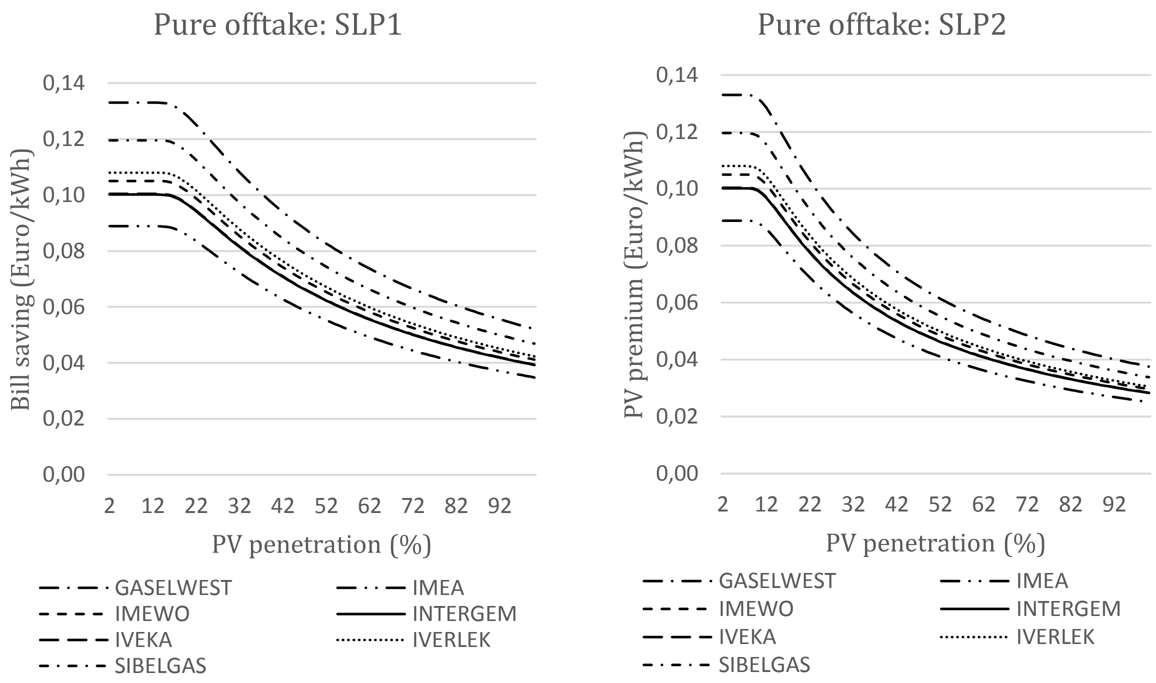

FIGURE 7: Bill savings under a pure offtake-related tariff policy.

4.4 Injection tariff policy

Figure 8 summarizes the results under a tariff policy combining offtake and injection tariffs. Bill savings are higher for SLP1 at each level of PV penetration, due to the better temporal correlation with the generation profile. Note that marginal benefits of PV generation decrease from a certain threshold. This threshold corresponds to the PV penetration where grid interaction is minimized, and is lower for SLP2 than for SLP1. From this threshold, additional generation has little room for further reduction of the annual offtake, instead increasing the annual injection. Note that the absolute differences in bill savings are similar to the bill savings under the pure offtake policy, because injection tariffs in Flanders (α_3) are relatively low compared to offtake tariffs (α_1). Furthermore, differences in bill savings between different DSOs become smaller as PV penetration increases. The reason for this is twofold: on the one hand annual offtake decreases, and consequently its impact on the final bill. On the other hand, annual injection increases, but the injection tariffs are low enough to nullify this effect on the bill.

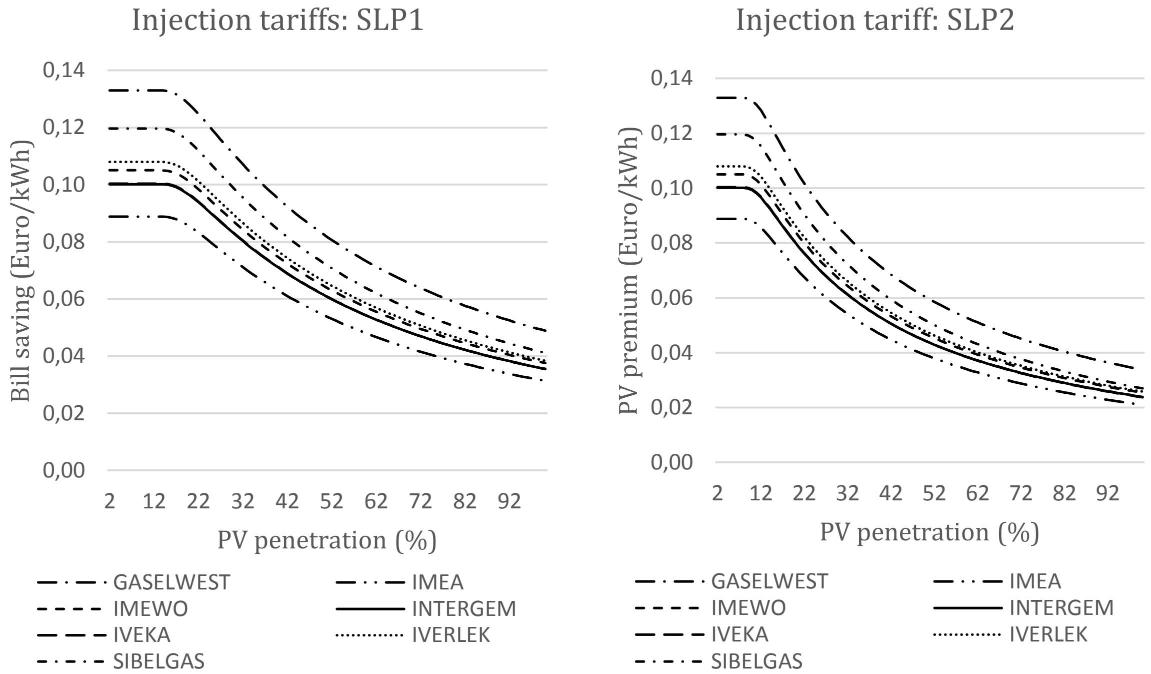

FIGURE 8: Bill savings under an offtake and injection tariff policy.

4.5 Peak metering

The results for the peak metering policy are summarized in Figure 9. Bill savings are higher for SLP1, because of two reasons. First, the tariff is partly based on the annual offtake, which depends on the shape of the load profile and is higher for SLP2. Second, the tariff is based on monthly peak demand, which can be reduced for SLP1, but not for SLP2. At ±10% PV penetration, marginal benefits of PV generation decrease because of lower offtake and peak demand reductions.

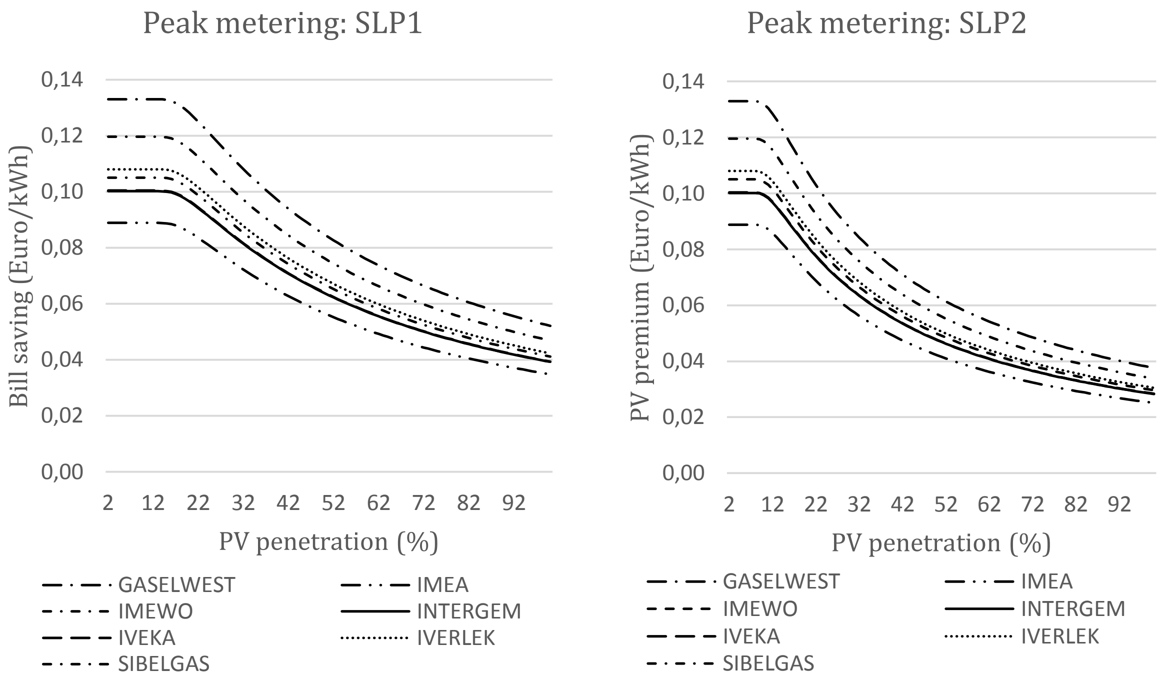

FIGURE 9: Bill savings under a peak metering policy.

5. Conclusion

In this paper, the electricity distribution bill savings per kWh generated are quantified under different tariff policies, and considering different load profiles and PV penetration levels. Assuming that the costs of the DSO after installation remain the same, these bill savings constitute a premium given to PV users, which is ultimately paid by the remaining consumers. Bill savings are computed using the distribution grid tariffs of seven DSOs in the Flanders region in Belgium. Results are obtained for an average Belgian residential consumer, and for a residential consumer who consumes more during night-time.

The results suggest that both the conventional and an advanced NEM policy with an additional capacity component provide no incentive to adjust the load profile or to scale the PV system in such a way that grid interaction and peak demand are reduced. The marginal PV premium per kWh generated is constant for increasing levels of PV penetration, despite the fact that beyond a certain threshold grid interaction increases and monthly peak demand does not decrease further. In other words, if the distribution grid tariffs are high enough, there is an incentive to install PV until at least a 100% penetration is reached. Whether or not further integration of PV beyond 100% is desirable, depends on banking regulations. A tariff component based on the capacity of the PV system equally discourages PV installation at each penetration level, including the lower levels where potential exists for marginal reductions in grid interaction and monthly peak demand.

In addition, it is found that pure offtake-related policies, mixed offtake and injection policies, and policies based on peak demand are better suited to incentivize a PV penetration level that minimizes grid interaction and reduces monthly peak demand. This is because marginal benefits of installing PV capacity decrease for higher levels of PV penetration. At the same time, tariffs can be designed in such a way that the absolute bill savings are similar to a NEM policy for small levels of PV penetration.

The results also suggest that for an average Flemish residential consumer, the ability of PV systems to reduce peak demand is limited, both in terms of the frequency and the size of the reductions. Even at 100% PV penetration, reductions during the summer period amount to 14%, with a PV penetration of approximately 10%. Increasing PV penetration above this threshold does not lead to significant marginal peak demand reductions. Similarly, PV systems provide limited room to reduce grid interaction. At 28% PV penetration, the average Flemish consumer can reduce his grid interaction by 20%.

It is also found that, if a regulator aims to employ PV systems to reduce peak demand and grid interaction, it is preferable to support installation of these systems at the premises of grid users with a load profile similar to SLP1. This is because SLP1 exhibits a higher temporal correlation with PV generation profiles than SLP2. The findings in this paper further confirm the hypothesis that NEM policies do not account for differences in shape of the load profile.

An important presumption in this paper is the idea that increasing levels of PV penetration have no impact on the total cost of the DSO and no impact on the total service volume. In other words, distribution grid tariffs are insensitive to changes in installed PV capacity. In order to quantify the true size of cross-subsidies between PV-users and pure consumers, one has to account for the effect of PV generation on the costs of the DSO. This remains an open topic for further research.

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